Agenda Date: 7/9/03
Agenda Item: 2A

Procedural

STATE OF NEW JERSEY

Board of Public Utilities
Two Gateway Center
Newark, NJ 07102
www.bpu.state.nj.us

ENERGY

I/M/O THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR APPROVAL OF CHANGES IN ELECTRIC RATES, FOR CHANGES IN THE TARIFF FOR ELECTRIC SERVICE, B.P.U.N.J. NO. 14 ELECTRIC PURSUANT TO N.J.S.A. 48:2-21 AND N.J.S.A. 48:2-21.1, FOR CHANGES IN ITS ELECTRIC DEPRECIATION RATES PURSUANT TO N.J.S.A. 48:2-18, AND FOR OTHER RELIEF	DECISION AND ORDER BPU DOCKET NO. ER02050303 OAL DOCKET NO. PUC 5744-02
I/M/O THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY'S DEFERRAL FILING INCLUDING PROPOSALS FOR CHANGES IN ITS RATES FOR ITS NON-UTILITY TRANSITION CHARGE (NTC) AND ITS SOCIETAL BENEFITS CHARGE (SBC) FOR THE POST TRANSITION PERIOD PURSUANT TO N.J.S.A. 48:2-21 AND N.J.S.A. 48:2-21.1	BPU DOCKET NO. ER02080604 OAL DOCKET NO. PUC 7893-02
I/M/O THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR A REVISION OF TARIFF B.P.U.N.J. NO. 13 ELECTRIC TO MODIFY THE BODY POLITIC LIGHTING SERVICE AND THE PRIVATE STREET AND AREA LIGHTING SERVICE	BPU DOCKET NO. ET01120830 OAL DOCKET NO. PUC 1186-03
I/M/O THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR APPROVAL TO TRANSFER ASSETS AND TO ENTER INTO A CONTRACT WITH PSEG SERVICES CORPORATION PURSUANT TO N.J.S.A. 48:3-7, N.J.S.A. 48:3-7.1 AND N.J.S.A. 48:3-55, AND FOR OTHER RELIEF	BPU DOCKET NO. EM00040253 OAL DOCKET NO. PUC 1187-03
I/M/O THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR DECLARATORY RULING CLARIFYING THE COST RESPONSIBILITY FOR NUCLEAR GENERATING ASSET DECOMMISSIONING FUNDS PURSUANT TO N.J.S.A. 48:3-49 ET SEQ. AND N.J.S.A. 52:14B-8	BPU DOCKET NO. EO02080610

I/M/O THE CONSUMER EDUCATION PROGRAM	)	BPU DOCKET NO. EO01120832
I/M/O THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY'S CONSUMER EDUCATION PROGRAM – YEAR THREE, AS EXTENDED THROUGH DECEMBER 31, 2002	)	BPU DOCKET NO. EO02110854
I/M/O THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY TO INCREASE THE LEVEL OF THE GAS DEMAND SIDE ADJUSTMENT FACTOR AND TO MAKE CHANGES IN THE TARIFF RATES BPU NJ NO.12 GAS PURSUANT TO N.J.S.A. 48:2-21, N.J.S.A. 48:2-21.1 AND N.J.S.A. 48:3-60(a)13, AND N.J.A.C. 14:21-1 ET SEQ.	)	BPU DOCKET NO. GR01040280

(SERVICE LIST ATTACHED)

BY THE BOARD:

On July 31, 2003, the Board of Public Utilities ("Board") issued a Summary Order (the "Summary Order") that memorialized the action taken by the Board in the above-docketed matters at its July 9, 2003 public agenda meeting. The Summary Order was issued for the purpose of implementing new rates for Public Service Electric and Gas Company ("PSE&G" or "Company") on August 1, 2003, consistent with the requirements of the Electric Discount and Energy Competition Act ("EDECA"), N.J.S.A. 48:3-49 et seq., and the Board's Orders implementing EDECA. The Board noted in the Summary Order that it would issue a Final Decision and Order that would provide a fuller discussion of the issues as well as the reasoning in support of the Board's determinations. This Final Decision and Order supersedes the Board's July 31, 2003 Summary Order.

The above-captioned dockets will be referred to herein as the "base rate proceeding," the "deferral proceeding," the "street lighting proceeding," the "service agreement proceeding," the "nuclear decommissioning proceeding, "the CEP Year Two," the "CEP Year Three," and the "DSAF proceeding," respectively.

I. BACKGROUND AND PROCEDURAL HISTORY

A. Base Rate Proceeding and
B. Deferral Proceeding

On May 24, 2002, Public Service Electric and Gas Company , a public utility located in the State of New Jersey, filed with the Board a petition seeking approval to: (1) increase the Company's base rates for electric distribution service revenues by $250.06 million, (2) increase the electric and gas field collection charges from $14.00 to $22.00, and (3) change the level of depreciation applicable to the Company's electric and common plant.

This petition is the first full base rate filing by PSE&G since the passage of EDECA, which took effect on February 9, 1999. A primary goal of EDECA was to foster competition in the provision of energy and, thereby, usher in retail choice for energy supply for the consumers in the State. Shortly after EDECA was enacted, the Board issued an Order that mandated retail choice. The Board also directed the State's four investor-owned electric utilities to: (1) unbundle their individual rate schedules, (2) provide basic generation service ("BGS") at Board approved rates for any customer who did not choose an alternate power supplier, (3) provide Board approved "shopping credits" which would be deducted from the bills of customers who choose an alternate power supplier, (4) reduce the aggregate level of rates for all customer classes of each utility by no less than 5 percent. N.J.S.A. 48:3-52(a)(d). Commensurate with the mandated rate reductions, EDECA permitted the four electric utilities, subject to Board approval, to: (1) establish a Societal Benefits Charge ("SBC") designed to recoup the costs associated with previously Board-approved social, environmental, and demand side management ("DSM") programs, which costs were a part of the utilities' bundled rates, and (2) implement a Market Transition Charge ("MTC") to allow each utility an opportunity to recover a Board approved level of stranded costs. N.J.S.A. 48:3-60(a); N.J.S.A. 48:3-61.

The passage of EDECA and subsequent Board actions implementing the legislation were preceded by other events that foreshadowed the movement toward a competitive energy market. Two years before the passage of EDECA, on April 30, 1997, the Board issued an Order adopting and releasing a report entitled: Restructuring the Electric Power Industry in New Jersey: Findings and Recommendations ("Final Report"). The Final Report was submitted to Governor Whitman and to the Legislature for review. As part of the Final Report, each of the four investor-owned electric utilities in the State was directed to prepare and file with the Board by July 15, 1997, three separate petitions in accordance with the guidelines and principles in the Final Report. The petitions, were required to address each electric utility's compliance with the various rates and competition mandates subsequently enacted into law as part of EDECA, included: (1) a rate unbundling petition, (2) a stranded cost petition, and (3) a restructuring plan.[1]

On July 15, 1997, PSE&G filed with the Board a single petition for its unbundling, stranded costs, and restructuring proposals. On that same day, PSE&G also filed its response to the Final Report. The unbundling and stranded costs portions of the petition were transmitted to the Office of Administrative Law ("OAL"). The Board retained the restructuring plan filing. Hearings were held on the petition at the OAL before Administrative Law Judge ("ALJ") Louis G. McAfoos. Subsequent to the issuance of the Initial Decision by ALJ McAfoos, two proposed stipulations of settlement, sponsored by two separate sets of the parties to the proceedings, were submitted to the Board. On April 21, 1999, the Board issued a Summary Order followed by a Final Decision and Order on August 24, 1999. I/M/O Public Service Electric and Gas Company's Rate Unbundling, Stranded Costs, and Restructuring Filings, BPU Docket Nos. EO97070461, EO97070462, and EO97070463, August 24, 1999 ("Restructuring Order").[2] The Restructuring Order modified the Initial Decision of ALJ McAfoos and also found that with certain modifications and clarifications, the Stipulation entered into by PSE&G and various other parties was more

[1] In addition to examining issues unique to each utility, the Board also conducted a generic review of issues common to the four electric utilities. The Board reviewed: (1) standards for fair competition, (2) affiliate relationship standards, (3) market power, and (4) the mechanics for the phase-in of customer choice.

[2] This Order was affirmed on appeal. In re Public Service Elec. and Gas Co., 330 N.J. Super. 65 (App. Div. 2000), aff'd 167 N.J. 377, cert.den. 534 U.S. 813 (2001).

financially prudent, consistent with EDECA's requirements and served as a reasonable framework for a resolution of the restructuring proceedings. Id. at 93

In its Restructuring Order, the Board mandated that PSE&G implement a total rate reduction of 13.9 percent that was to be phased-in over the four year transition period beginning on August 1, 1999 and terminating on July 31, 2003 consistent with N.J.S.A. 48:3-52(d). Id. at 115-117. The Board also ordered an amortization of a $568.7 million excess found in the Company's depreciation reserve account. The Board ordered an amortization of the excess amount over a three year and seven month period starting on January 1, 2000 and ending July 31, 2003. Id. at 115. The Board also determined that the Company was entitled to recover up to $2.94 billion net of tax of its generation related stranded costs and, further, authorized the Company to securitize $2.4 billion of the net-of-tax generation-related stranded costs. Id. at 117. The Company was also given the opportunity to recover the remaining $540 million of generation related stranded costs through a Market Transition Charge pursuant to N.J.S.A. 48:3-61. Id. at 118.

The Restructuring Order also addressed a methodology to properly account for the Company's deferrals of costs resulting from the unbundling of its base rates. Pursuant to the Restructuring Order, the Company established (1) a Societal Benefits Charge to recover the costs of various programs to be implemented under N.J.S.A. 48:3-60, and (2) a Non-Utility Transition Charge ("NTC") that was part of the MTC discussed above, and designed to recover net actual above-market non-utility generation ("NUG") contract costs. Id. at 117-118. The Restructuring Order further confirmed that the Company would be able to recover those BGS costs incurred as part of its obligation to provide basic generation service pursuant to N.J.S.A. 48:3-57. Id. at 121. The review and recovery of the actual costs, as opposed to any costs approved throughout the transition period, would be deferred until the end of the transition period. In order to allow sufficient time for the Board to review the amounts contained in the deferred accounts and determine the total recovery, as well as to reset base rates, the Company was directed to file a petition with the Board no later than August 1, 2002.

On May 24, 2002, PSE&G filed a petition with the Board pursuant to N.J.S.A. 48:2-21, N.J.S.A. 48:2-21.1, and N.J.S.A. 48:2-18, requesting approval of increases to its base rates for electric distribution service, electric and gas field collection charges, and depreciation rates applicable to its electric and common plant. I/M/O Petition of Public Service Electric and Gas Company for Approval of Changes in Its Tariff for Electrical Service, Depreciation Rates and for Other Relief, BPU Docket No. ER02050303. The Company requested an increase of $250.06 million in distribution revenues, a change in its current field collection charge of $14.00 to $22.00, and a change in its electric and common general plant depreciation rates. The proposed effective date of August 1, 2003, coincided with the termination of the four-year transition period approved by the Board in its Restructuring Order. The matter was transmitted to the OAL as a contested case on June 26, 2002 and was assigned to ALJ Richard McGill.

At its agenda meeting of June 26, 2002, as memorialized in its July 22, 2002 Order Directing the Filing of Supplemental Testimony and Instituting Proceedings to Consider Audits of Utility Deferrals, BPU Docket Nos. ER02050303, EO97070461, EO97070462, and EO97070463, the Board determined that the Company's filing failed to address directives contained in the Restructuring Order and other Orders. In addition, the Board found that the petition lacked sufficient data needed to allow a full examination of the Company's deferred amounts and thus make a finding as to the Company's post-transition rates. The Board directed the Company to file supplemental testimony addressing the directives contained in the Board's previous Orders. The supplemental testimony would be a newly docketed matter addressing the deferral issues.

The Board set no later than August 30, 2002 as the filing date for the petition for the deferral matters to be newly docketed. The Board further directed that the rate case and deferral petition be heard separately but be consolidated into one initial decision.

On July 19, 2002, ALJ McGill held a prehearing conference on the base rate filing, at which representatives for the Company, the Division of the Ratepayer Advocate ("RPA"), and Board Staff ("Staff") participated. ALJ McGill issued his Prehearing Order on July 24, 2002.

During the course of the rate case proceeding, the ALJ received motions for intervention or participation from various entities. ALJ McGill granted intervention to Co-Steel Raritan, Inc.[3] ("Co-Steel"), Independent Energy Producers of New Jersey ("IEPNJ"), New Jersey Large Energy Users Coalition ("NJLEUC"), New Jersey Transit Corporation ("NJ Transit"), New Jersey Commercial Users ("NJCU");a group of municipal utilities and sewer departments including Stony Brook Regional Sewerage Authority, Mount Holly Municipal Utilities Authority, Secaucus Municipal Utilities Authority, Cinnaminson Sewerage Authority, East Windsor Municipal Utilities Authority, Riverside Sewage Authority, Evesham Municipal Utilities Authority, Willingboro Municipal Utilities Authority, Somerset Raritan Valley Sewage Authority, Bordentown Sewage Authority, Morris Township Sewage Department, Monroe Township Municipal Utilities Authority and Pemberton Municipal Utilities Authority (collectively "MUA" or "Municipal Utilities Authority Intervenors"), Delaware River Port Authority, and the Township of Hamilton . Participant status was granted to Jersey Central Power and Light Company ("JCP&L"), Rockland Electric Company ("RECO"), PPL EnergyPlus, LLC. ("PPL") and Allen Goldberg.

Duly noticed public hearings for the receipt of public comment were conducted for the rate case in areas throughout the Company's service territory. Public hearings were held in New Brunswick on September 25, 2002, Mt. Holly on September 26, 2002, and Hackensack on September 30, 2002. Additional public hearings were held in Mercerville and Mt. Holly on January 30, 2003 and in Newark on January 31, 2003. Evidentiary hearings were held on January 13, 14, 17, 21, 24, 27, 28, 29 and 31 and on February 24, and March 19, 2003.

On January 13, 2003, Staff moved to consolidate with the rate case, two matters that were previously filed with the Board: <u>I/M/O the Petition of Public Service Electric and Gas Company for Approval To Transfer Assets and to Enter Into a Contract with PSEG Services Corporation</u>, BPU Docket No. EM00040253 (filed December 1999), and <u>I/M/O the Petition of Public Service Electric and Gas Company for Approval of Changes in Its Tariff for Electric Body Politic Lighting Service and Private Street and Area Lighting Service</u>, BPU Docket No. ET01120830 (filed December 2001). Staff's motion for consolidation of these two cases was due to the Board's above-referenced July 22, 2002 Order. In that Order, the Board also directed that if the two cases were not resolved within 60 days of the date of the Order, then they would be transmitted to the OAL. On receiving the full record of both cases, ALJ McGill granted Staff's motion for consolidation.

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[3] During the course of the proceeding, Co-Steel Raritan, Inc., changed its name to Gerdau Ameristeel Perth Amboy. To avoid confusion, this Order will use the name Co-Steel when referring to Gerdau Ameristeel Perth Amboy.

On August 28, 2002, the Company filed its deferral petition[4] as required by the above-referenced Board Restructuring Orders and July 22, 2002 Order. The Company's deferral petition proposed a reduction effective August 1, 2003 in annual revenues of approximately $122.4 million to its electric SBC and NTC rates.

Pursuant to its July 22, 2002 Order, the Board also authorized issuance of a Request for Proposal ("RFP") to hire an independent auditor to perform an audit on each of the State's electric distribution companies ("EDCs"), and an RFP was thereafter issued. Request for Proposal to Perform Audits of the Deferred Balances of New Jersey's Four Electric Utilities, Docket Nos. EX02060363, EA02060366. After reviewing various proposals, the Board selected Mitchell and Titus LLC ("Mitchell & Titus") and Barrington-Wellesley Group, Inc., ("BWG") (collectively the "Auditors") to perform an audit of PSE&G's electric restructuring related deferred balance incurred through July 2003. The scope of the audit covered the deferred balance accounts, transactions, and supporting calculations for the Transition Period for each utility. The Board's overall objective was to obtain certified opinions as to whether the utility's deferred balances were correct and included costs that were reasonable, prudently incurred, properly calculated and recorded, and in compliance with all applicable Board Orders. The Board directed the Auditors to determine whether the Company's BGS procurement procedure was prudent, and whether any purchased power was made at reasonable prices relative to a competitive wholesale market and consistent with appropriate hedging techniques. The Board further directed the Auditors to review the Company's mitigation efforts with regard to above-market NUG contract costs during the Transition Period.

On transmittal of the Company's deferral petition to the OAL, the matter was consolidated with the pending base rate filing. On October 24, 2002, ALJ McGill held a prehearing conference on the Company's deferral petition. The parties included the Company, RPA and Staff. In addition, the ALJ granted motions to intervene by NJLEUC, IEPNJ, and Co-Steel, and motions to participate by RECO and JCP&L. Public hearings were conducted in Mt. Holly, New Brunswick, and Hackensack, on December 10, 11, and 16, 2002, respectively. Evidentiary hearings were held on March 2, 3, and 6, 2003 during which witnesses for the Company, RPA, Co-Steel and the Mitchell and Titus team presented testimony.

The parties filed initial briefs April 3, 2003, and reply briefs on April 17, 2003. By letter dated June 6, 2003, several parties to the proceeding, PSE&G, Co-Steel, New Jersey Transit, and Independent Energy Producers of New Jersey, submitted a Settlement to ALJ McGill proposing to resolve all issues pending in the base rate and deferral proceedings, as well as various other proceedings as discussed more fully below.

On June 6, 2003, the ALJ issued his Initial Decision accepting the Settlement as resolving all issues pending before him. In his Initial Decision, the ALJ indicated that, in view of time constraints, any objections to the proposed Settlement of the base rate and deferral proceedings should be submitted to the Board via Exceptions.

On June 23, 2003, Exceptions were received from PSE&G. On that same date, Joint Exceptions were filed by the New Jersey Large Energy Users Coalition, the New Jersey Commercial Users, and the Municipal Utilities Authority Intervenors (jointly filing as the "Customer Parties") and Concurring Exceptions were filed by the Municipal Utilities Authority

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[4] I/M/O the Petition of Public Service Electric and Gas Company's Deferral Filing Including Proposals for Changes in Its Non-Utility Transition Charge ("NTC") and Its Societal Benefits Charge ("SBC") for the Post-Transition Period Pursuant to N..J.S.A. 48:2-21 & 48:2-21.1, BPU Docket No. ER02080604.

Intervenors. A letter dated June 23, 2003, was received from Board Staff indicating that it would not file Exceptions but instead relied on its initial and reply briefs. Replies to Exceptions were filed on June 30, 2003 by PSE&G, the Customer Parties, and Co-Steel.

C. Street Lighting Proceeding

In I/M/O the Energy Master Plan Phase 2 Proceeding to Investigate the Future Structure of the Electric Power Industry, Docket Nos. EX94120585Y, EO97070461 ("EMP Order") the Board approved several changes to the Company's street lighting rates in effect at that time. Rate Schedule SL, Street Lighting Service was separated into two rate schedules: Body Politic Lighting Service ("BPL") and Private Street and Area Lighting ("PSAL"), in compliance with the Board's Order dated January 27, 1994 in Docket No. ER91111698J. Only a body politic could take service under the BPL rate and receive the quantity discount available to such entities under the old Rate Schedule SL. Rate PSAL was available for private street and outdoor area lighting.

The EMP Order also resulted in the unbundling of the costs related to electric supply for Rate Schedules BPL and PSAL. Formerly bundled costs were separated into two main categories, those monthly charges based on the specific type of luminaire or pole, and those based on the energy use of a specific luminaire. In addition, costs based on kilowatt hour usage were further unbundled into specific components in the Rate Schedules. As a result of the Board's Order in the EMP case, customers of the Company were able to select a Third Party Supplier ("TPS") to meet their street light energy needs.

On December 7, 2001, the Company filed a petition with the Board seeking approval to restructure its BPL and PSAL Rate Schedules. The Company proposed no bill or rate impact to any existing street lighting customer.

On July 22, 2002, the Board in its Order Directing the Filing of Supplemental Testimony and Instituting Proceedings to Consider Audits of Utility Deferrals, directed the parties to the street lighting proceeding, the Company, RPA, and Staff, to either settle the case within sixty days of that Order or the matter would be transmitted to the OAL for inclusion as part of the Company's pending rate case.

The parties conducted negotiations. By letters to Board Secretary Izzo dated September 23, 2002, October 30, 2002, and November 15, 2002, the parties requested additional time in an attempt to settle the matter. The parties were unable to reach settlement and on January 15, 2003 , the case was transmitted to the OAL with instructions to consolidate it with the pending base rate case.

On February 19, 2003, the RPA filed the testimony of its expert witness in the case, David E. Peterson. A hearing on the matter was held before ALJ McGill on February 24, 2003.

By letter dated April 3, 2002, the parties submitted to ALJ McGill a Settlement of the case. The ALJ accepted the Settlement in his above-referenced Initial Decision dated June 6, 2003.

D. Service Agreement Proceeding

On April 20, 2000, PSE&G filed a petition with the Board seeking authorization and approval to transfer certain assets and contracts to PSEG Services Corporation ("Service Company") necessary to the operation of the Service Company pursuant to N.J.S.A. 48:3-7 and 48:3-55.

PSEG is a subsidiary of Public Service Enterprise Group Inc., ("PSEG"), a public utility holding company of which PSE&G is a regulated subsidiary. In the alternative, the Company requested that the Board find that the proposed transfer is in the ordinary course of business. The petition also sought authorization and approval of a service agreement governing the provision of services between PSE&G and the Service Company pursuant to N.J.S.A. 48:3-7.1.

On July 28, 2000, the parties to the proceeding, the Company, RPA, and Staff, agreed to a discovery/ procedural schedule that provided for discovery, initial and reply comments to be completed by November 2000. On October 27, 2000, the RPA filed a letter memorandum with the Board setting forth its comments in response to the petition. The Company filed its response on November 17, 2000. By letter dated March 20, 2001, the Company submitted revised schedules and a request for Board approval of the petition.

In its July 22, 2002 Order Directing the Filing of Supplemental Testimony and Instituting Proceedings to Consider Audits of Utility Deferrals, the Board directed the parties to either settle the matter within sixty days or the matter would be transmitted to the OAL for determination. By letter dated September 20, 2002, the Company sought an extension of the transmittal of the matter to the OAL.

On January 15, 2003, the matter was transmitted to the OAL where it was consolidated for hearing with the pending rate case. On February 15, 2003, the RPA filed the testimony of its expert witness in the case, David E. Peterson. A hearing was held on the matter at the OAL before ALJ McGill on February 24, 2003.

By letter dated April 17, 2003, a Settlement entered into by PSE&G, the Service Company, the RPA and Board Staff was filed with the ALJ. As described more fully below, the parties agreed to a settlement of the Company's petition as amended on March 20, 2001 but reserved one issue involving the allocation of indirect Service Company costs to be resolved in the base rate proceeding. The Settlement was approved by the above-referenced Initial Decision of June 6, 2003.

E. Nuclear Decommissioning Proceeding

In its August 24, 1999 Restructuring Order, the Board approved the transfer of PSE&G's ownership interests in the Salem, Peach Bottom, and Hope Creek nuclear units to PSEG Power, an unregulated affiliate. On August 21, 2000, an Asset Transfer Agreement was executed whereby, as of that date, PSEG Power would assume all liabilities and obligations associated with decommissioning of the aforementioned nuclear units.

The actual cost to decommission the nuclear units was determined as part of the Company's 1992 base rate proceeding. I/M/O the Petition of Public Service Electric and Gas Company for Approval of the 1990 TLG Decommissioning Studies and the Nuclear Decommissioning Costs, Docket No. EE91081428 (December 31, 1992). Based on the projections made a part of the record in that case, the cost of decommissioning the nuclear units was estimated in 1990 dollars at $681 million or $4.8 billion when valued at the time of the nuclear units' license terminations. In anticipation of this projected cost, the Board approved annual decommissioning funding by the Company's ratepayers in the amount of $22.6 million for 1993, escalated to $29.6 million in 1994. The amounts were collected in irrevocable external trusts known as Nuclear Decommissioning Trust Funds ("NDTF"). These external trusts were created at the time that the nuclear units were placed into service. The balances in the NDTF, totaling approximately $664 million, were transferred to PSEG Power as part of the Asset Transfer Agreement.

The Board, in its Restructuring Order, set August 1, 1999, as the beginning of the four-year transition period to implement the provisions of EDECA. The Restructuring Order also authorized the inclusion in the Company's SBC of the annual decommissioning funding of $29.6 million pursuant to N.J.S.A. 48:3-60(a)(2). The Board in its Restructuring Order further directed the Company to file within ninety days of the Restructuring Order a specific proposal that would limit the financial responsibility of the Company and its ratepayers for funding of nuclear decommissioning costs. The Company responded by letter dated November 23, 1999, that revenue issues associated with decommissioning costs and the revised estimated costs based on an updated decommissioning study should be addressed in the Company's upcoming distribution rates filing.

In compliance with the Restructuring Order, the Company filed its electric distribution base rate petition on May 24, 2002. As previously noted, by Order dated July 22, 2002, the Board further directed the Company to file supplemental testimony as part of the base rate proceeding. Among other things, the Board's directive sought a more specific proposal for limiting ratepayer funding of decommissioning costs. The Company responded to the Board's July 22, 2002 directive by filing a petition for a Declaratory Order regarding decommissioning cost responsibility on August 28, 2002.

A prehearing teleconference was held on March 27, 2003. Pursuant to the schedule established at the prehearing conference, direct testimony was filed by the Company and RPA on April 11, 2003, and April 22, 2003, respectively. Rebuttal testimony was filed by the Company on May 1, 2003, and by the RPA on May 9, 2003. Evidentiary hearings were conducted at the Board on May 13 and 14, 2003, with Commissioners Carol J. Murphy presiding. The Company and RPA filed their initial briefs on June 16, 2003. Staff filed its initial brief on June 18, 2003. Reply briefs were filed on June 25, 2003.

As described more fully below, a resolution and closing of the nuclear decommissioning proceeding was included in the Settlement of the base rate and deferral proceedings approved by the above-referenced Initial Decision of June 6, 2003.

F. Consumer Education Program Proceedings

1. CEP Year One and Two

On March 31, 2001, the Company completed the second year ("Year Two") of the Consumer Education Program ("CEP"), required by the Board pursuant to EDECA's mandate to establish a consumer education program to prepare energy consumers for the restructuring of the State's electric and gas industries. On December 19, 2001, the Company filed with the Board a petition for recovery of $6.188 million, plus interest, in Year Two electric CEP costs and $3.874 million in Year Two gas CEP costs. The petition sought immediate recovery of Year Two gas CEP costs, and a declaratory ruling that the Company's Year Two electric CEP costs were reasonable. I/M/O the Consumer Education Program, Docket No. EO02210832. Because of the cap on electric rates, the Company requested August 1, 2003 as the effective date for recovery of the Year Two electric CEP costs and interest. The Company requested a total $14.369 million for its electric CEP costs (for Years One and Two), plus interest. The Company's request for Year Two gas CEP costs totaled $8.996 million, which amount included an uncollected balance of $4.570 million from Year One CEP expenditures and interest. A combination public/evidentiary hearing was held on September 30, 2002 before ALJ McGill.

2. CEP Year Three

On March 31, 2002, the third year of the original CEP program ("Year Three") was completed, however, pursuant to the Board's April 8, 2002 Order of Extension in Docket No. EX99040242, and a letter dated July 23, 2002 from the Board's Secretary, the CEP program was extended through December 31, 2002. On November 12, 2002, the Company filed a petition with the Board that reiterated its prior request for approval of its pending Year Two gas CEP costs and for approval and recovery of its Year Three gas CEP costs through December 31, 2002. I/M/O Public Service Electric and Gas Company's Consumer Education Program – Year Three, as Extended through December 31, 2002, Docket No. EO02110854. The petition requested $1.872 million, excluding interest, in Year Three CEP gas expenses for a total of $11.644 million in CEP gas costs, including interest, which total accounts for prior unrecovered CEP gas costs from Year One and Year Two, and for CEP gas costs and interest incurred in Year Three. The Company proposed to implement its gas SBC adjustment effective for service rendered on and after the Board's written Order. The Company also sought approval of the reasonableness of $2.992 million, excluding interest, of Year Three electric CEP costs.

The Company's request for Year One, Year Two, and Year Three electric CEP costs, as extended through December 31, 2002, totaled $19.967 million, including interest. The Company requested an effective date of August 1, 2003 for recovery of these costs.

As described more fully below, a resolution and closing of the CEP Year Two and Three proceedings was included in the Settlement of the base rate and deferral proceedings approved by the June 6, 2003 Initial Decision.

G. Gas Demand Side Adjustment Factor/Electric Demand Side Management

On April 30, 2001, PSE&G filed with the Board a motion for authorization to increase the level of its Gas Demand Side Adjustment Factor ("DSAF") effective January 1, 2002, or on a date as determined by the Board. I/M/O the Motion of Public Service Electric and Gas Company to Increase the Level of the Gas Demand Side Adjustment Factor and to Make Changes in Tariff Rates B.P.U.N.J No. 12, Gas Pursuant to N.J.S.A. 48:2-21, N.J.S.A. 48:2-21.1, and N.J.S.A. 48:3-60(a)(3), and N.J.A.C. 14:12-1 et seq., Docket No. GR01040280. The Company's motion also sought a declaratory ruling for (1) costs incurred for Electric Demand Side Management ("DSM") programs, including recoverable lost revenue from January 1998 through December 2000, (2) a Board finding that the costs are reasonable and prudently incurred, and (3) Board approval for the recovery of these costs through the SBC.

On May 7, 2001, the matter was transmitted as a contested case to the OAL and was assigned to ALJ William Gural. Two public hearings were held on the matter. On August 7 and 8, 2001, public hearings were held in Hackensack and New Brunswick, respectively. An evidentiary hearing was held at the OAL on November 28, 2001. Initial briefs were filed by the Company, RPA, and Staff on March 15, 2002. Reply briefs were filed by the Company and RPA on April 12, 2002.

On July 17, 2002, the parties executed a Stipulation. Summarized, the key provisions to the Stipulation provided:

1) The disallowance of $100,000 ($60,000 electric and $40,000 gas) for the HESP audits program that could have continued through the 1998 program year.

2) The disallowance of $100,000 ($60,000 electric and $40,000 gas) relative to the E-Team Partners low-income program.
3) The resolution of all issues pertaining to gas and electric DSAF issues through May 9, 2001.
4) The Company agreed to support the RPA's position moving the New Jersey Comfort Partners low-income program from utility administration to a Board approved non-utility administrator.
5) The Company agreed to consider opportunities to buy back standard offer contracts when requested by individual contractors, if such a buy back can be deemed to be in the best interests of customers.
6) The Gas DSAF of 1.2824 cents per therm sold excluding Sales and Use Tax ("SUT") will be implemented as of the date of the Board's written Order in the DSAF proceeding. The revised rate will provide approximately $32.7 million of additional DSAF revenues (including SUT) and will amount to an increase of approximately 1.0 percent for a typical residential gas customer using 100 therms.
7) Projected Gas DSAF costs for 2002 increased by $544,000 from $42,046,000 to $42,590,000.
8) All gas DSM program costs, including lost revenue and excluding the disallowances above, incurred by the Company from June 1998 through
9) May 9, 2001 (the start of the Comprehensive Resource Analysis ["CRA"] programs) are reasonable and prudently incurred and are eligible for recovery through the SBC,
10) All electric DSM program costs, including lost revenue, and excluding the disallowances, incurred from January 1998 through May 9, 2001 (start of the CRA programs) are reasonable and prudently incurred and are eligible for recovery through the SBC.

The ALJ issued his Initial Decision accepting the Stipulation on July 24, 2002. On September 18, 2002, the Board requested a 45-day extension from the OAL for issuance of a Final Determination in order to review the issues and the extensive record.

On October 9, 2002, the parties executed an addendum to the Stipulation, whereby they agreed that since the recovery of electric DSM costs to be approved by the Board will be through the electric SBC clause, this amount is subject to the audit provisions detailed in the Board's July 22, 2002 Order directing the filing of supplemental testimony and instituting proceedings to consider audits of utility deferrals.

On October 31, 2002, the Board issued its Decision and Order in which the Board adopted the Initial Decision and Stipulation as modified by the addendum, finding them to be just and reasonable and in the public interest. The Board ordered the Company to implement the gas DSAF of 1.2824 cents per therm (excluding SUT) effective on the date of the Order. In addition, the Board reserved its final decision on the reasonableness and prudence of all electric DSM expenditures until after the conclusion of the then ongoing deferred balance audit.

As described more fully below, a resolution and closure of this matter was included in the Settlement of the base rate and deferral proceedings approved by the June 6, 2003 Initial Decision.

II. INITIAL DECISION APPROVING SETTLEMENTS

On June 6, 2003, ALJ McGill issued his Initial Decision approving three Settlements which had been submitted to him: (1) a Settlement of the street lighting matter submitted by the Company by letter dated April 3, 2003; (2) a Settlement of the Services Company proceeding submitted by the Company by letter dated April 17, 2003, and (3) a Settlement resolving the base rate and deferral proceedings, and a remaining issue with regard to the Service Company proceeding, and deeming certain other proceedings, including the nuclear decommissioning proceeding, CEP Years Two and Three, and DSAF proceedings, closed and resolved. The key provisions of the Settlements are described more fully below.

A. Settlement of Base Rate, Deferral and Certain Other Proceedings - This Settlement was entered into by PSE&G, NJ Transit, IEPNJ, and Co-Steel.

1. Base Rate Proceeding

a. Revenue Requirement

The settling parties agreed that electric base rate revenues should be increased by $170 million on an annual basis for service rendered on and after August 1, 2003, based on a rate base of $3,092 million with an overall weighted rate of return of 8.18 percent and a return on equity of 9.75 percent, with a test period pro forma operating income of $114.7 million and reflecting the agreed upon amortization of the excess depreciation reserve described below.

The settling parties recommend that the Board approve a decrease to the Company's rate of depreciation for financial reporting and ratemaking purposes for electric distribution plant from 3.52 percent to 2.75 percent to be effective at the same time that the new base rates are implemented. Certain other depreciation rates were agreed upon for electric common and general plant, as set forth in the settlement.

An excess depreciation reserve of $155 million will be amortized over 29 months beginning on August 1, 2003 as a kilowatt-hour credit of ($0.001565) per kWh applicable to all kWh to which the Transition Bond Charge is applied. For purposes of billing, the credit shall be combined with the NTC charge. At the expiration of the 29-month credit term, there will be a reconciliation of the $155 million credit and any over-recovery or under-recovery balance will be transferred to the NTC deferred balance.

The base rate case revenue requirement reflects a ten-year amortization of the Company's accumulated restructuring costs of $43.732 million resulting in a levelized revenue requirement $6.068 million. The base rate case revenue requirement also includes a ten-year amortization of the accumulated repair allowance of $58.052 million, net of tax, producing a levelized revenue requirement of $13.663 million.

The settling parties also agreed that, absent emergent circumstances, the Company will not file a petition for an increase to its electric distribution rate to become effective prior to January 1, 2006.

b. Cost of Service/Tariff Design

Except as modified by the terms of the Settlement, the parties agreed to the rate design/tariff as proposed by the Company through its petition, direct testimony, and exhibits.

The parties agreed that tariff language proposed by the RPA explaining the reasons for the Generation and Transmission Obligations as provided in Alternate Original Sheet No. 80 attached to Exhibit CS-9 will be included in the final tariffs submitted to the Board.

ISE provisions of Rate Schedules LPL and HTS will be eliminated and all ISE credits will end as of August 1, 2003. In addition, the Company will maintain the CES tariff provision; however, the Company will only call for curtailments of selected distribution service customers if reduction of loading on the distribution system is necessary to maintain its reliability, or if curtailment would postpone the need to upgrade the distribution system where the economic value of the postponement exceeds the CES payments.

In regard to the RLM rate, the Settlement provides that in addition to the current annual notice to RLM customers, the Company will provide additional information in the form of a bill insert or bill message regarding the rate and its potential benefits to customers.

The Settlement recommends that Area Development Service currently provided for in the Company's tariff should be reviewed and updated by the Board, as needed, as part of the Board's review of the pending Smart Growth filing. Until the Board completes its review, and orders any change to the current Area Development program, the Company's current Area Development credit mechanism and credit level will remain in effect.

The Settlement provides for the continuation by the Company of including loss factors in the calculation of the charges for the SBC and NTC. The manner of calculating the charges will be similar to that in the current tariffs.

The Rate LPL rate schedule for NJ Transit traction accounts will include language that will allow them to be treated in the manner afforded them in the current HTS tariff. In addition, the Settlement provides for supplemental traction power language to be included in the HTS rate schedule.

The Settlement provides for an apportionment across the rate classes for the increase to distribution revenues. The Settlement incorporates Attachment 3 which, as represented by the Company, was prepared by first developing an Average Percentage Customer Bill Change (column 8). In column 8, the initial rate changes were based on the Company's cost of service study, limited by the Company's testimony recommending that in the spirit of gradualism no customer class should receive more than 150% of the average system delivery increase and no class should receive less than 50% average delivery increase.

The Settlement provides for adjustments to the service charge. For residential service under Rate Schedule RS, the proposed service charge is set at $2.27. The proposed summer second block Distribution Charge would be .3822 cents higher than the summer first block and the winter second block Distribution Charge would be equal to the winter first block.

For Rate Schedule RHS, the proposed service charge is $2.27. The summer second block Distribution Charge would be .4900 cents higher than the summer first block and the winter second block Distribution Charge would be 1.76 cents lower that the winter first block.

In order to maintain the total service charge revenue from Rate Schedule GLP customers at current levels, the Settlement provides for the GLP service charge to be $3.96 and the

Unmetered Service Charge to be $1.83.

For Rate Schedules GLP, LPL-Secondary, LPL-Primary, HTS-Subtransmission, and HTS-High Voltage, the Settlement provides that the Transitional Electric Facilities Assessment ("TEFA") and the excess depreciation reserve amortization will be recovered through kilowatt hour (kWh) charges. In place of the Company's proposed rate design for Rate Schedules GLP, LPL-Secondary and LPL-Primary, the balance of the distribution revenue requirement to be recovered through kW (demand) and kWh (energy) charges will be apportioned between new distribution kW and kWh charges in each of these rate schedules, so as to maintain the relationship between total kW and kWh revenues in each of these rate schedules in present rates. In lieu of the Company's proposed rate design for Rate Schedules GLP, LPL-Secondary and LPL-Primary, the Annual Demand Charge will be determined on and applied to the customers' highest Monthly Peak Demand in any time period of the current month in lieu of the proposed Annual Peak Demand. For customers served under the standby provision of these rate schedules, the Annual Demand Charge will be applied to the customer's Annual Peak Demand. For Rate Schedules HTS-Subtransmission and HTS-High Voltage, the Annual Demand Charges and Summer Demand Charges are shown in Attachment 4 of the Settlement.

The Settlement resolves standby issues by adding standby provision language into the definition of Monthly Peak Demand in Rate Schedules GLP, LPL, and HTS.

Under the terms of the Settlement, the Company's Field Collection Charge for both its electric and gas tariffs will be increased from $14.00 to $16.00. The Company's Reconnection Charge would increase from $15.00 to $20.00. In addition, the proposal to allow the Company to require the installation of remote metering equipment at the customer's expense was eliminated.

The Settlement provides for a new rate schedule effective April 1, 2005 for the present service location of Co-Steel in Perth Amboy. The rate schedule will be identical to HTS-HV except that in lieu of the HTS-HV Service Charge and the HTS-HV Distribution Charges, Co-Steel will be billed a fixed annual amount of $305,000, billed in equal amounts in each month plus applicable unit taxes, and will not be responsible for any remaining BGS cost recovery related to the BGS amounts deferred from the twelve month period ending July 31. 2003. These provisions will not apply if Co-Steel qualifies for and opts to take service under an alternate rate schedule. In addition, the Settlement provides that Co-Steel will incur costs for various charges: TBC, MTC-tax, SBC (except DSM and RAC), and NTC, for the first 20 million kWh per month rather than the current 13 million kWh per month. This proposal would take effect on the expiration of Co-Steel's current contract with PSE&G.

The parties agreed that in the Company's next base rate proceeding, the Company will submit at the time of its filing, a cost of service study based on the directions in discovery Exhibit S-63 (S-PRD-53 Revision 2) as clarified in Staff's initial brief in this proceeding at pages 116-117. The Settlement further provides that all parties will be free to submit any number of alternative cost of service methodologies for the Board's consideration in future cases and no party will be obligated to rebut the methodology offered by another party in order to establish the justness and reasonableness of any particular methodology.

2. Deferral Proceeding

The Settlement provides for a $238.4 million reduction to the Company's SBC/NTC revenues for a period of 29 months effective for service rendered on and after August 1, 2003, simultaneously with the new electric distribution base rates discussed above. In order to achieve this reduction, the Settlement reflects the following adjustments:

a. The proposed revenues under the NUG component of the NTC will be reduced to result in a return to customers of $64.3 million as opposed to the $47.6 million originally proposed by the Company.

b. An estimated Year Four Basic Generation Service under-recovery of $241.5 million is included in the Settlement at an annual amount of $28.1 million. In the event the Board approves a securitization of the Year Four BGS under-recovery and the securitization take place by May 1, 2004, the charge established in Attachment 2 for this item will be used for the interim period to collect the BGS under-recovery. The recovery of the BGS under-recovery during the interim period will be accounted for by first assessing on a monthly basis a carrying cost to the net of tax BGS under-recovered balance equal to a monthly rate based on the one-year constant maturity treasuries as shown in the Federal Reserve Statistical Release on or closest to August 1, 2003 plus 50 basis points. The residual of revenues collected in any month will be used to adjust the BGS under-recovered balance. This carrying cost is for the sole and exclusive purpose of determining a rate of interest for the interim period prior to a Board approved securitization taking place.

In the event that the Board has approved a securitization of the Year Four BGS under-recovery and the securitization transaction has not occurred by May 1, 2004, the charge established in Attachment 2 for this item will be used for the interim period to collect the BGS under-recovery. The recovery of the BGS under-recovery will be accounted for by first assessing on a monthly basis a carrying cost to the net of tax BGS under-recovered balance equal to a monthly rate based on the two-year constant maturity treasuries as shown in the Federal Reserve Statistical release on or closest to August 1, 2003 plus 60 basis points. The residual of revenues collected in any month will be used to adjust the BGS under-recovered balance. This process will continue until securitization occurs. This carrying cost is for the sole and exclusive purpose of determining a rate of interest for the interim period prior to a Board approved securitization taking place.

In the event that the Board does not approve a securitization of the Year Four BGS under-recovery or securitization cannot be accomplished, the settling parties recommend that the appropriate carrying charge effective August 1, 2003 reflect a cost of capital that is commensurate with the time frame of amortization authorized by the Board.

c. If the Board approves a securitization of the Year Four BGS under-recovery and upon such securitization a separate irrevocable nonbypassable securitization or transition bond charge ("TBC-BGS") and a separate related MTC-tax (BGS) to recover the unsecuritized related taxes are implemented, such charges, TBC-BGS and MTC-tax (BGS), would replace the BGS component of the NTC charge identified in Attachment 2. The difference between the BGS charge included in Attachment 2 and the actual securitization charges, both TBC-BGS and MTC-tax (BGS), whether positive or negative shall be deferred in the NTC. When the NTC is reset, it will include the deferred effect related to the difference between the charge shown on Attachment 2 and the TBC (BGS) and the MTC-tax (BGS).

d. The MTC over-collection will be increased $18 million to recognize positions of the parties with respect to MTC collections and $30 million to recognize positions of the parties in the nuclear decommissioning case, for a total $48 million increase that will be returned to customers over a 29-month period.

e. After July 31, 2003, the electric SBC will no longer include the recovery of nuclear decommissioning costs from customers. The Company's unregulated affiliate, PSEG Power, will assume the cost responsibility for decommissioning its nuclear units. The Company's customers will have no responsibility for nuclear decommissioning costs and will not have any right to the funds contained in the nuclear decommissioning trusts, and the Settlement resolves all issues raised in the Nuclear Decommissioning Proceeding, Docket No. EO02080610, which should be closed.

f. Interest accrued during the transition period on deferred balances, other than Remediation Adjustment Clause ("RAC") balances, is calculated on a net-of-tax basis for all components of the NTC and SBC. For deferred balances other than the RAC and the Year Four BGS, the interest rate effective August 1, 2003, will be based on two-year constant maturity treasuries as shown in the Federal Reserve Statistical Release on or closest to August 1, 2003, plus 60 basis points. For RAC balances, the interest rate will be based on seven-year constant maturity treasuries as shown in the Federal Reserve Statistical Release on or closest to August 1, 2003, plus 60 basis points. Both rates shall change on each subsequent August 1. The interest calculation methods shall also apply to gas SBC deferrals effective August 1, 2003.

g. The RAC component of the SBC reflects the Company's recently approved RAC 9 settlement.

h. The gain on the sale of the Kearny Unit No. 12 has been reflected on a pre-tax basis.

i. From May 2001 until the Board approves the protocols for measuring energy savings under the New Jersey Clean Energy Program, the Company will defer lost revenues based on its energy savings as reported in the quarterly New Jersey Clean Energy Program reports filed with the Board. Once the protocols are approved, they may be used for lost revenues on a prospective basis.

j. In resolution of the unresolved issue from the Service Company proceeding, the parties agreed that in developing additional revenues under this Settlement, BGS and BGSS revenues were excluded from the Company's Proposed Modified Massachusetts Formula and the Revenue, Earnings and Capital Expenditures Formula for allocating Service Company costs to PSE&G.

k. The Company shall file annual updates on its efforts to mitigate NUG contract costs and the Company will also continue to sell NUG power costs into the PJM Spot Market, unless and until the Board determines that a different protocol is appropriate.

l. The parties to the Settlement agreed that to the extent the Board orders an interim or permanent Universal Services Fund or Lifeline program cost, the Company will receive full and timely recovery through the electric and gas SBCs for the cost of these programs.

3. Nuclear Decommissioning

As noted above, the settling parties agreed that customers will no longer pay through the nuclear decommissioning component of the SBC for nuclear decommissioning costs, formerly $29.6 million per year. The Company's unregulated affiliate generating company will assume the cost responsibility for nuclear decommissioning with a corresponding elimination of the nuclear decommissioning component of the SBC. The Settlement provides that the Company's customers will not have any claim on funds contained in the nuclear decommissioning trusts. The Company's Market Transition Charge over collection, will be increased by $30 million, which is the approximate annual nuclear decommissioning cost paid by the Company's customers through the SBC, and returned to those customers over a twenty-nine month period following July 31, 2003. The nuclear decommissioning proceeding will be deemed closed and resolved.

4. CEP

The parties agreed that the electric portions of the Year One, Two and Year Three CEP filings are deemed closed and resolved. The settlement provides that the total CEP costs, including the Year Two and Year Three gas costs, which are common to the CEP costs reviewed herein, are reasonable. The parties further recommend that the Board authorize recovery of the gas CEP costs through the Company's gas SBC.

5. Electric Demand Side Management Adjustment Factor

Upon the effective date of the Board's written Order approving the Settlement, the DSAF proceeding will be deemed closed and resolved. Pursuant to the Board's October 31, 2002 DSAF Order, the Company implemented recovery of the increase in its Gas Demand Side Adjustment Factor. The Board reserved, however, its decision on the reasonableness and prudence of the electric DSM expenditures pending the conclusion of the deferred balance audit. The deferred balance audit was part of the overall deferral proceeding. As noted above, in the Settlement of the deferral case, the signatories agreed to a $238.4 million reduction in SBC/NTC revenues. Included as part of that $238.4 million reduction, was a component associated with electric DSM costs totaling $61.5 million.

B. Settlement of the Street Lighting Proceeding

A Settlement signed by the parties to the proceeding, the Company, RPA, and Staff, was submitted to the ALJ on April 3, 2003, and is summarized below.[5]

For body politic lighting, both street and area lighting will continue to be served on Rate Schedule BPL. The prices and terms for service for the maintenance, delivery, and energy service for publicly owned street lighting facilities, currently part of Rate Schedule BPL, will be separated into a new separate Rate Schedule BPL-POF. This will simplify the BPL Rate Schedule without affecting the pricing, applicability, or availability of POF service.

[5] The Settlement of the base rate, deferral, and other cases also provided that consistent with the Street Lighting Settlement, that matter should be closed.

All luminaires and poles provided under rate schedules BPL and PSAL will be classified as either “standard” or “specialty” items. Standard luminaries and poles are defined as all closed luminaries (those installed that are no longer offered) plus all other luminaries and poles listed in the tariff sheets for Rate Schedules BPL and PSAL. The Company will continue to bill all standard and current specialty luminaires and poles for both BPL and PSAL at existing rates. Specialty luminaires and poles with more than 50 installed will become standard luminaires and standard poles at the conclusion of the Company’s subsequent base rate proceeding and the standard prices established in that proceeding will apply to future installations of those luminaire and pole types.

The Monthly Charge Per Unit for all BPL Specialty Luminaires, installed after the effective date of the new tariff sheets, will be calculated as the sum of the Capital Recovery Charge and Maintenance Charge as described in the Street Lighting Stipulation. (Street Lighting Stipulation, paragraph 6, 6a, and 6b, at 5-6).

All poles not listed in the BPL tariff sheets as Standard Poles, all non-standard installations of standard poles, and all shrouds, brackets, and other miscellaneous devices will be deemed Specialty Poles. The Monthly Charge Per Unit for all BPL Specialty Poles after the effective date of the new tariff sheets will be calculated as the sum of the Capital Recovery Charge and Maintenance Charge as described in the Street Lighting Stipulation. (Street Lighting Stipulation, paragraph 7, 7a, and 7b, at 6).

The Monthly Charge Per Unit for all PSAL Specialty Luminaries installed after the effective date of the new tariff sheets will be calculated as the sum of the Capital Recovery Charge and Maintenance Charge as described in the Street Lighting Stipulation. (Street Lighting Stipulation paragraph 8, 8a, and 8b, at 6-7).

All poles not listed in the PSAL tariff sheets as Standard Poles, all non-standard installation of standard poles, and all shrouds, brackets, and other miscellaneous devices are deemed Specialty Poles. The Monthly Charge Per Unit for all PSAL Specialty Poles installed after the effective date of the new tariff sheets will be calculated as the sum of the Capital Recovery Charge and Maintenance Charge as described in the Street Lighting Stipulation. (Street Lighting Stipulation, paragraph 9, 9a, and 9b, at 7-8).

In addition to required contributions, Body Politic customers, at the time of installation, may elect to contribute to the total installed cost of certain facilities up to the maximum contributions as described in the Street Lighting Stipulation. (para. 10, 10a, and 10b, at 8). In addition, the Company may limit the contribution option between zero and the maximum contribution. PSAL customers installing lighting facilities for construction projects, where upon completion of the project the customer of record will be a body politic, may also elect to contribute to the total installed cost of certain luminaries or poles.

The tariff sheets for Rate Schedules BPL, BPL-POF, and PSAL as proposed by the Company in its electric base rate petition will be modified to include: (1) incorporation of the specific terms of the Street Lighting Stipulation; (2) updating of charges consistent with the Board’s Order in the electric base rate case, including the carrying charges specified in the Street Lighting Stipulation for the Board approved cost of capital; (3) any other changes in the Board’s Order resolving the electric base rate case; and (4) the elimination of all references to a “Knockdown Charge”; (5) all dates shown as January 1, 2002 will be changed to August 1, 2003.

C. Settlement of the Service Agreement Proceeding

By letter dated April 17, 2003, the Company filed with the ALJ a Settlement executed by the Company, the Service Company, Staff, and the RPA, (the parties) to the Service Agreement Proceeding. The Settlement resolves all issues in the matter, except for one. The remaining issue to be briefed and resolved through litigation, involves whether Basic Generation Service and Basic Gas Service Supply ("BGSS") revenues should be excluded from the revenue component of the Company's Proposed Modified Massachusetts Formula and the Revenue, Earnings, and Capital Expenditures Formula for allocating indirect Service Company costs to the Company.[6]

Regarding the remaining issues resolved by the Settlement, pursuant to the Service Agreement between PSE&G and Service Company costs will be directly charged wherever possible to the Company from the Service Company, with a goal of maintaining or improving the current total cost allocations to the Company of 84 percent.

The parties agree that the Boards' approval of the petition will not affect or limit the Board's authority regarding rates, franchises, accounting, capitalization, depreciation or other matters that are within the Board's jurisdiction as affecting the Company.

The Company will account for any plant acquired by the Company from the Service Company whether capitalized or expensed, in accordance with the Company's capitalization policy. Further, the Company will present test year data for billings from the Service Company on a basis consistent with the Company's capitalization policy and on basis of the actual billings, if different.

The Service Company's charges will be based on fully allocated costs that include carrying costs that is a return on and of the assets used by the Service Company in the provision of services to the PSEG operating companies. For asset-related carrying charges billed to PSE&G, the "return on" component of the carrying charge, will be based on the then authorized rate of return for PSE&G. The "return of" component of the carrying charge will be based the Service Company's depreciation lives, which in no case will be less than the lives of PSE&G. As for assets of PSE&G that are used by the Service Company, charges by PSE&G will be based on fully allocated costs in accordance with PSEG's currently effective Cost Allocation Manual. These costs will also include carrying costs on assets used by the Company in the provision of service to the Service Company. Asset-related carrying charges to the Service Company will be based on the Company's currently authorized rate of return and book depreciation accrual rates.

In the first quarter of each year, the Company will submit to the Board and RPA: (1) a report on the Service Company's billings, showing the prior year's total annual dollar amount and percentage of direct versus allocated costs for each PSEG operating company, including a specific breakdown for PSE&G operations, (2) a report describing for each PSEG affiliate the new year's cost allocation percentages for Service Company charges for each methodology with a further breakdown for PSE&G operations, and including work papers, and (3) copies of

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[6] As noted above, this unresolved issue was resolved by the Settlement of the base rate, deferral and other proceedings, and that Settlement also provided that the Service Company proceeding should be deemed closed and resolved.

the Board's or its consultant's prior public external audit reports regarding the Company's affiliate relations.

The Company agrees, with prior reasonable notice, to permit the Board Staff and RPA access, at the Company's offices, to previous PSEG sponsored external audits and internal audit reports pertaining to the evaluation or testing of the Service Company's determination of direct billings and cost allocations to its affiliates. The Company also agrees to provide the Board with full access to its records, and to any records of the Service Company, which records will be maintained in New Jersey, or to records of other affiliates involved in transactions with the Company as these records may relate to the provision of services to the Company. Neither this provision nor any other provision of the settlement is intended to limit the Board's authority pursuant to Title 48.

With regard to intercompany debt and working capital, PSE&G will be charged a rate of return equal to the Service Company's overall cost of capital. However, PSE&G will not be charged a rate higher than its authorized rate of return.

PSE&G agrees that the Board, under its authority pursuant to EDECA to audit PSE&G's affiliate relationships every two years, including access to the books and records of the Service Company and other affiliates which pertain to services that they provide to PSE&G and in the Board's reviewing authority under New Jersey statutes and regulations in PSE&G's base rate case proceedings, may review the allocation of costs in sufficient detail to analyze their reasonableness, the basis for the allocation of borrowing cost and working capital, the type and scope of services that the Service Company provides to PSE&G, and the basis for inclusion of new participants in the Service Company's allocation formula. PSE&G and the Service Company shall record costs and cost allocation procedures in sufficient detail to allow the Board to analyze, evaluate and render a determination as to their reasonableness for ratemaking purposes.

The transfer of assets, which appear on Attachment G to the Settlement, to the Service Company will be at the net depreciated book value of the assets within 30 days of the issuance of an Order approving the Settlement.

The Company's proposed service agreement as amended shall be approved as reasonable. The Company agrees to provide notice to the Board and RPA within 30 days prior to implementation, of all substantial changes to the Service Agreement, including provision of services to a non-affiliate third party, and additions or deletions in the categories of services provided by the Service Company and any substantial changes in the cost allocation bases and methodologies for indirect charges. The parties agree that the notice will be for discussion and not for pre-approval purposes. Nothing in either this Settlement expressly or impliedly connotes agreement on the part of the Staff or the Ratepayer Advocate that the Company's customers will be responsible for payment through rates of costs resulting from such notified charges. The parties reserve their rights as to positions they may take regarding the rate-making treatment of the noticed costs. The Service Agreement includes costs to the Company for Investor Relations and Governmental Affairs. These costs are for book purposes, and the Settlement provides that the Staff and the RPA reserve their rights as to their positions on whether these costs will become the responsibility of the Company's customers.

The Company has the ability to opt-out, without penalty, of any service supplied by the Service Company that it determines can be procured more economically, is not of an acceptable quality level, or for any other valid reason. Prior to exercising its option, the Company must first attempt to resolve the matter with the Service Company.

Notwithstanding the provisions of this Settlement, parties hereto continue to be bound by any future Board Orders regarding the Service Company, such as may result from the Competitive Service Audit currently being performed by the Liberty Consulting Group in Docket No. EA02020097.

III. EXCEPTIONS AND REPLY EXCEPTIONS

A. Exceptions

Exceptions to ALJ McGill's June 6, 2003 Initial Decision were received from: PSE&G, the New Jersey Large Energy Users Coalition, the New Jersey Commercial Users, the Municipal Utility Authority Intervenors, and Board Staff. Exceptions addressed only the Settlement of the base rate, deferral and other above-referenced proceedings.

1. PSE&G

Although the ALJ, in his Initial Decision, accepted the base rate and deferral Settlement of PSE&G and several of the intervenors, the Company filed exceptions in the form of comments in support of the Initial Decision approving the Settlement.

Petitioner notes the strong state policy favoring settlement over litigation of contested matters. Furthermore, the Company asserts that the policy to encourage negotiated resolutions of matters extends to stipulations involving less than all of the parties to a case. (PSE&G Exceptions at 5-6). The Company points to the importance of the participation of the active parties (including the RPA and Board Staff) in the negotiations, and to the significance of the signatories to the settlement being knowledgeable and well-informed regarding the issues to the case. (Id. at 9).

As to the Company's electric distribution revenue requirement, the Company asserts that the Settlement figure of $170 million in additional electric distribution revenues based on a rate base of $3,092 million is well within the range of net increases supported in the record. (Id. at 13). The Company notes that its last increase in base rates was over ten years ago, in 1993, and that based on its 12-0 update in the record, a $298.2 million increase was supported. (Id. at 3).

The Company's comments also address and cite to record support for the Settlement's resolution of other electric distribution revenue requirement issues, including its stipulated operating income (Id. at 14); depreciation rate and pre-tax excess depreciation reserve (Id. at 15); accumulated repair allowance (Id. at 16), and cost of capital of an overall weighted average 8.18percent rate of return, using a 9.75percent return on equity as had been recommended by Board Staff. (Id. at 16-17).

Regarding the deferral proceeding, the Company's comments note that the Settlement reduces the Company's Societal Benefits Charge and the Non-Utility Transition Charge by $238.4 million, which the Company notes is approximately $39 million greater than the original net revenue reduction of $199.5 proposed by the Company in the deferral case. (Id. at 17). The Company's comments also address actual non-utility generation expenses under the NTC, the securitization of the under-recovery of Year Four Basic Generation Supply cost, the over-collection of the Market Transition Charge, the resolution of the nuclear decommisioning case, and the deferral of lost revenues under the New Jersey Clean Energy Program. (Id. at 17-21).

The Company also supports provisions of the Settlement regarding cost of service and rate design issues and cites to support in the record for each of the various provisions. The Company asserts that the Settlement's inter-class revenue allocation is based on the cost to serve the various customer classes, as well as on consideration of the impact the rate changes may have on the various customer classes. (Id. at 22-26). The comments also discuss and cite to record support for the resolution of intra-class rate design issues, including loss factors in the SBC and NTC charges, rate schedules LPL and HTS Traction Power, Rate Schedules RS, RHS, and GLP Service Charges, Rate Schedules RS and RHS Winter-Summer rate design, the allocation of the increase to Demand and Energy Charges, Standby Service, and other tariff issues. (Id. at 37-43).

**2. New Jersey Large Energy Users Coalition
New Jersey Commercial Users
Municipal Utilities Authority Intervenors**

The above parties, filing as the "Customer Parties," submitted Joint Exceptions to the Initial Decision. The Joint Exceptions fault the absence of many important parties to the case as signatories to the Settlement; the lack of meaningful input by these same parties; the lack of in-depth consideration by the ALJ, who received the Settlement on the day the Initial Decision was due; and the magnitude of the revenue increase. (Id. at 2-9). The Customer Parties argue that approval of the $233.8 million revenue increase, which it asserts is "buried" in the Settlement, together with the 29-month bill credit mechanism, would guarantee an automatic rate spike, without any further filings or review by the Board, upon expiration of the credit at the end of 29 months in January, 2006. (Id. at 6, 8-9). They urge the Board to reject the Settlement's crediting mechanism and instead adopt approaches of Staff and the Ratepayer Advocate, whereby to return the excess depreciation reserve to ratepayers, the amortized amount was rolled into the base rate calculation, thereby affording ratepayers the protection of a revenue increase number that could only be changed by Board order after a full rate case. (Id. at 9-11). The Joint Parties urge the Board to reject the Settlement's 29-month amortization and, instead, accept the five-year amortization of the excess depreciation balance as proposed by Staff. (Id. at 10-11).

The Joint Exceptions also criticize the lack of a substantial basis in the record in support of the proposed revenue requirement and key elements on which it is premised. (Id. at 11-12). Although the Customer Parties urge rejection of the Settlement, because new distribution rates need to be in place by August 1, 2003, they note that time constraints preclude returning the matter to ALJ McGill for issuance of an Initial Decision on the litigated positions. (Id. at 12-13). The Customer Parties recommend that a straightforward method of deriving a more reasonable distribution revenue requirement may be achieved by adopting a depreciation rate of 2.49 percent, as recommended by Staff and the RPA, and an annualized excess depreciation figure of $31 million, representing the Staff-recommended five-year amortization of the $155 million excess depreciation reserve. (Id. at 13). The Customer Parties indicate that this would result in an approximate $156 million distribution revenue increase, which should be subject to change only through a future rate filing. (Id. at 14). The Customer Parties further recommend that all rate classes have their respective distribution revenue changes shown in the Settlement adjusted proportionately to reflect the revenue requirement decrease. (Id. 12-14).

3. Municipal Utilities Authority

The Municipal Utilities Authority filed Concurring Exceptions as well as joining the Joint

Exceptions of the Customer Parties. The MUA shares with the Customer Parties a concern with the nature of the process through which the Settlement was reached and the lack of parties to the Settlement who were active and involved in all issues to the case, and note that none of the signatories had contested revenue requirement or interclass rate design issues. (Id. at 2). They assert that particularly troubling to them was that during settlement discussions, there had been insistence by a party that the settlement include a provision, unacceptable to the MUA, that a specific interclass cost allocation methodology is reasonable and appropriate for future PSE&G rate cases, unlike most settlements which do not establish precedent for future cases. (Id. at 2). They allege that thereafter they only learned of further settlement discussions when the core of the proposed settlement was not discussable and not changed. (Id. at 3). The MUA cites a failure of the Settlement to resolve all issues to the case, the overall magnitude of the increase in revenues to the Company, and the lack of consideration of any offset by a pro-forma adjustment for any lower cost of debt in the Company's capital structure at the time of the "second step" increase on January 1, 2006. (Id. at 4-8). The MUA criticizes the Settlement for not recognizing recent changes in the capital markets and the lack of any modification in the Settlement's rate of return. (Id. at 8). The MUA also questions the basis for any "compromise" or changed depreciation rate given the 2.49 percent rate advocated by the Company and approved by the Board in the Company's restructuring proceeding and given the lack of a filed request by the Company for the depreciation rate changes herein. (Id. at 9).

The MUA also discusses cost allocation and rate design relying on its filed Initial and Reply Briefs. (Id. at 10-12). Highlighting certain of its contentions, the MUA argues that because this case involves the just and reasonable rates to cover expenses, return on investments, and recognition of revenues at existing rates related to PSE&G's distribution plant or "the wires," the distribution of the rate increase among customer classes should be based on the relationship of each class's wires-related revenues at present rates to PSE&G's wires-related cost. (Id. at 10). The MUA argues that instead, however, the Settlement apportions the rate increase based on limiting changes in overall cost, with the result that, although the LPL classes should have a lower than average increase in wires-related rates to bring their rates to full wires cost, they are improperly apportioned a higher than average increase. (Id. at 10-11). It further argues that the Settlement's distribution of the wires increase to LPL Primary and HTS classes, and possibly others, is designed to subsidize generation services, unrelated to wires-related costs, to other customer classes. (Ibid.) The MUA also argues that the Area Development Rate reflects a discount based on economic cost to serve considerations that may have existed in the past when the rate was first created almost 20 years ago, but which no longer exist and that, therefore, the rate is unduly discriminatory and should not be continued pending further review as proposed by the Settlement. (Ibid.)

4. Board Staff

Board Staff did not file formal Exceptions, instead filing a letter advising that it would rely on the positions contained in its Initial and Reply Briefs.

B. Replies to Exceptions

1. PSE&G

The Company argues that the Settlement contains mutually balancing and interdependent provisions reflecting numerous compromises. The Company argues that the acceptance of the settlement by the ALJ was proper. It points to the lengthy and complex process that included the testimony of experts, many days of hearing, numerous exhibits, and the filing of briefs, thereby resulting in the development of a full record. (Id. at 6). The Company notes that ALJ McGill presided over the entire proceeding, is experienced in utility matters and utility rate setting and was well positioned, following the hearings and full briefing, to assess the reasonableness of the Settlement. (Id. at 7). The Company further notes that the acceptance of the Settlement by the ALJ was procedurally correct and consistent with prior Board and judicial decisions. (Id. at 7-9).

The Company asserts that the Settlement is reasonable, amply supported by the record in the case, and consistent with sound rate setting policy and Board precedent, and will result in just and reasonable rates, maintaining rates below 1999 levels through 2006, at which time there will be only a relatively modest increase. (Id. at 15-20).

PSE&G notes that the excess depreciation reserve is amortized as a credit with an equivalent revenue credit provided to customers, and when the amortization expense credit ends, the revenue credit does as well, with no impact on the Company's reported earnings. (Id. at 2). The Company criticizes the "rolled-in" approach proposed by the Customer Parties in their Joint Exceptions. The Company argues that the proposed methodology would improperly place into base rates the revenue credit associated with the excess depreciation reserve. By placing the revenue credit into base rates, the amortization of the booked excess depreciation reserve, which is timed to expire at the same time as the revenue credit, could expire without the corresponding expiration of the revenue credit. The Company asserts that this approach will cause it to experience an automatic revenue shortfall that would most likely trigger another rate proceeding. (Id. at 3.). It argues that such a rate case trigger point would be an unnecessary burden on the Company, the Board, customers and stakeholders, and that the stipulated approach properly recognizes and matches revenues with the expiration of the credit, just like with a change in an adjustment clause charge. (Ibid.). It also argues that the MUA's alternative claim that upon expiration of the $64 million annual credit on January 1, 2006, the Board should undertake an adjustment for lower costs of debt in the capital structure, ignores prior Board treatment of expiring ratepayer credits, and that the MUA's proposal would improperly change one element of a "comprehensive and balanced stipulated resolution." (Id. at 19-20).

PSE&G also contends that the Settlement is the result of arms-length negotiations and reflects concessions to meet positions of Staff and the RPA, although they did not sign the Settlement. The Company lists the concessions contained in the Settlement that differ from many of its litigated positions, including a reduction in the level of the August 1, 2003 revenue increase that would be justified, from $298.2 million based on its 12 + 0 update, to $170 million; an increase in operating income from $88.5 million based on its 12 + 0 update, to $114.741 million; a reduction in the return on equity from 11.6 percent to Staff's proposed 9.75 percent; a reduction in the depreciation rate, from 3.52 percent to 2.75 percent and the stipulated creation of an excess depreciation reserve of $155 million, and associated annual bill credit of $64 million over a 29-month period; agreement to write off approximately $48 million to reflect positions of other parties with respect to MTC collection and nuclear decommissioning expenses, and an additional write-off related to the net-of-tax interest approach for the transition period in response to the Staff and RPA's recommendation that interest should be calculated on the deferred balances net of associated deferred income taxes. (Id. at 10-11; 16-18).

PSE&G argues that while the excepting parties claim the $170 million revenue increase is temporary and focus on the $233 million figure they assert is "buried" in the Settlement, the $170 million revenue increase is the level that will actually be experienced by customers for two-and-a-half years. PSE&G also asserts that the excepting parties also ignore that the $64 million annual revenue credit to be provided over a 29-month period represents the amortization of an excess depreciation reserve, the existence of which is tied to a presumption of a lower depreciation rate having been in effect, which PSE&G disputed in the record and on which PSE&G compromised. (Id. at 12). PSE&G also contends that the Settlement does not "bury" information nor does the Company's public disclosures regarding the Settlement. (Ibid. PSE&G also argues as to the Settlement's depreciation rate that the Ratepayer Advocate's recommended 2.49 percent depreciation rate relied upon by the excepting parties is "grossly understated" and does not account for the cost of removal, and that when the cost of removal is included, the Ratepayer Advocate's 2.49 percent is increased to 2.76 percent. (Id. at 17-18). Thus, it argues that the Settlement's 2.75 percent depreciation rate has credible support in the record and ensures sufficient removal cost recovery. (Id. at 18).

2. Customer Parties

The Customer Parties filed Joint Reply Exceptions in the form of a Letter Memorandum. The Customer Parties point to the Exception process as underscoring the lack of support for revenue requirements aspects of the Settlement by any party, other than the Company, and reiterate their contention that, from their perspective, the negotiation process was "meaningless." (Joint Reply Exceptions at 2-3). The Customer Parties also allege that the Company is now attempting to "spin" the circumstances surrounding the Settlement and charge the Company as failing to be forthcoming as to the full impact of the Settlement. (Id. at 3-5). There is, however, an acknowledgement that a "fair and reasonable" resolution of the proceeding is possible. Consistent with the Joint Exceptions, the Customer Parties urge the Board to review the Settlement and modify only those revenue requirement issues as identified in the Joint Exceptions. (Id. at 3). They urge the Board to reduce the distribution revenue increase to $156 million as set forth in their Joint Exceptions. (Id. at 5).

The Joint Reply Exceptions also correct a statement contained in the Company's Exceptions regarding NJLEUC witness, Jeffrey Pollack. The Customer Parties note that Mr. Pollack did not agree with Company witness, Gerald Schirra's "total bill" approach to gradualism. Instead, Mr. Pollack argued that considerations of gradualism in setting rates should be based solely on changes in distribution costs. (Id. at 5-6).

3. Co-Steel

Co-Steel filed a letter as Reply Exceptions by which it supports the Settlement. It argues that there is no basis for the Board to find any part of the Settlement specific to Co-Steel as unjust, unreasonable, or unduly discriminatory. (Co-Steel Reply Exceptions at 1-2). Co-Steel submits that even if the Board accepts the litigated position of Staff concerning an alternative cost of service methodology, an annual distribution revenue requirement for Co-Steel of $305,000 as set forth in the Settlement should still be utilized insofar as it exceeds the cost-based revenue requirement supported by its witness and, as such, represents a reasonable compromise of the parties' positions. (Id. at 2). It notes that Board approval of the Settlement would increase the likelihood that its Perth Amboy plant will remain viable, while Board rejection of the Settlement and Co-Steel's litigation positions would force the plant's closure and the loss of PSE&G's single largest electric customer. (Ibid.)

IV. DISCUSSION AND FINDINGS

Based on the Board's careful review and consideration of the extensive record in these proceedings, including the Exceptions and Replies to Exceptions, the Board **HEREBY ADOPTS** the Street Lighting and Services Company Settlements as reasonable resolutions of those proceedings, but the Board is not fully satisfied that the proposed Settlement of the base rate, deferral and other proceedings is an appropriate resolution thereof. However, the Board **FINDS** that, with modifications and clarifications set forth below, elements of the proposed Settlement of the base rate, deferral and other proceedings provides a framework for a reasonable and fair resolution of these matters based on the record before it. Accordingly, except as specifically noted and explained below, the Board **HEREBY INCORPORATES** by reference as if completely set forth herein, as a reasonable and fair resolution of the issues in these proceedings, the elements of the proposed Settlement filed by PSE&G and others, and to the extent the Initial Decision is inconsistent herewith, it is **MODIFIED** as set forth below. The depreciation rate for electric distribution plant for financial and ratemaking purposes shall be 2.49 percent and not the 2.75 percent contained in paragraph 4 of the proposed Settlement. The Board **FINDS** that 2.49 percent is the distribution plant depreciation rate that should have been used by the Company beginning August 1, 1999. As was argued by several parties in the base rate case, including Staff and the RPA, as of December 1998, the Company had an excess distribution plant depreciation reserve of $568.7 million. This excess depreciation reserve was based upon a 2.49 percent distribution plant depreciation rate, and was calculated based upon the Company's request in the restructuring proceeding to extend the average plant service life used to establish the depreciation rate for the Company's distribution plant investment from 28 years to 45 years. In the absence of a formal depreciation study, the Board **FINDS** that the Company should use the 2.49 percent rate supporting the 45-year average distribution plant service life, rather than the 2.75 percent rate contained in the proposed Settlement.

The Board **FINDS** that the proposed Settlement's 29-month amortization of the excess depreciation reserve will ensure an expeditious and timely return to ratepayers of this excess.[7] Therefore, the Board accepts the Settlement's proposed 29-month amortization and rejects the requests for a 5-year amortization and for the credit to be built into the rate calculations. While the Board finds it unnecessary to embody the credit in the rate calculation itself, the Board **FINDS** unacceptable that, pursuant to the proposed Settlement, upon the expiration of the proposed bill credit associated with the amortization of the $155 million excess depreciation reserve, the Company will receive an automatic increase to its electric rates effective January 1, 2006, without the need for any further action by the Company or review by the Board. Instead, the Company shall be required to make a filing that will allow the Board to review its financial condition prior to January 1, 2006, to consider the $64.2 million of proposed additional rate increase associated with the expiration of the amortization of the $155 million excess depreciation reserve. The review shall include, but not be limited to, the examination of the Company's earnings, credit quality, and other indicators of overall financial integrity and shall be subject to the full participation of the parties to this proceeding and final determination by the Board.

Accordingly, the Board **HEREBY DIRECTS** that PSE&G shall make a financial review filing with the Board by November 15, 2005, and provide copies to all the parties in Docket No. ER02050303. The Board **HEREBY DIRECTS** Staff to convene a meeting of all interested parties within 30 days of the date of this Decision and Order to discuss the review process and the specific parameters to be used in measuring the need for additional rate relief. At a minimum, PSE&G's filing shall include the following for the calendar years 1999 through 2004, and for the 12 months ended September 30, 2005, unless otherwise noted:

[7] Commissioner Hughes dissents from this finding for the reasons set forth separately below.

a) the utility's capital structure and embedded costs at year or period end;

b) debt financings made during the year or 12-month period (including the issuance of transition bonds), indicating the principal amount issued, the term of the issue, coupon rate, issuance expenses and call and other significant provisions, if any;

c) the balance of short-term debt outstanding at year or period end and the average interest rate paid during the year;

d) bond interest coverage ratios and other metrics on which the bond rating agencies' ratings are based (the ratio of fixed funds from operations (FFO) to total debt, FFO interest coverage, pre-tax interest coverage and the ratio of total debt to total capital);

e) common equity issuances by the parent company, if any, indicating the shares sold, the price received and issuance expenses;

f) preferred equity issuances by the utility, if any, indicating the shares sold, the price received and issuance expenses;

g) capital contributions from and dividends paid to the parent company;

h) the achieved overall rate of return and rate of return on the utility's beginning and end average book common equity;

i) the utility's bond and other debt ratings assigned by the three major rating agencies (Moody's, Standard and Poors and Fitch) and copies of the related utility credit reports, as well as investment recommendations made for the parent company during the period;

j) capital expenditures on utility distribution plant;

k) with the exception of the rating agency reports, projections of the preceding information (a) – (j) are also to be provided for the forecast years 2006 through 2008;

l) for the 12 months ended September 30, 2005, employing all actual data, statements of rate base and utility operating income, both with and without the $64.2 million base rate increase associated with the amortization of the excess depreciation reserve, accompanied by an explanation and derivation of all adjustments;

m) on the same test year basis as (l), the utility's interest coverage ratios and other metrics on which the rating agencies' bond ratings are based, as well as the utility's overall rate of return and rate of return on common equity, with and without the $64.2 million increase; and

n) schedules showing the transmission investment, revenue and operating expenses eliminated in (l) in determining the distribution rate base and operating income, as well as a narrative explaining the basis for the transmission/distribution allocation.

As a result of the above modifications, the Board **HEREBY APPROVES** a base rate increase of $159.5 million, including the revenue increase associated with increases in the field collection and reconnection charges, rather than the $170.0 million base rate increase contained in the proposed Settlement at paragraph 1, for service rendered on and after August 1, 2003. The $159.5 million increase reflects a rate of return on equity of 9.75 percent and an overall rate of return of 8.18 percent, consistent with the proposed Settlement at paragraph 2 and well within the range presented in the record. Indeed, as noted by PSE&G, the return on equity is at the lower end of that range.

Additionally, pursuant to EDECA, and subject to a true-up of the Company's deferred Basic Generation Service balance as of July 31, 2003, to reflect the results of the Board's Phase II Audit, the inclusion of actual data through that date and a recalculation of the interest necessitated by these adjustments, the Board **HEREBY AUTHORIZES** recovery of a deferred BGS balance of $241.5 million as projected in the proposed Settlement. As provided in the proposed Settlement, the Board **HEREBY APPROVES** interim recovery of this balance at the rate of $28.1 million per year, pending the Board's decision on the Company's securitization petition. After reflecting a reduction in the non-utility generation component of the Company's Non-Utility Transition Charge of $64.3 million, the net effect of the interim BGS deferral recovery and the reduction in the NUG component is a reduction in the NTC of $36.2 million.

As also provided in the proposed Settlement, the Board **HEREBY APPROVES** a reduction in the Company's Societal Benefits Charge of $202.1 million. This includes a reduction of $43.7 million in the nuclear decommissioning component, which, in turn, reflects the discontinuance of such funding on the part of PSE&G's ratepayers as of August 1, 2002. In addition, the $202.1 million refund includes a refund of the Company's over-recovered Market Transition Charge deferred balance of $105.4 million; a reduction of $61.5 million in charges for Demand Side Management and Clean Energy Program costs; a reduction in social program costs of $10.9 million; an increase in the Remediation Adjustment Clause of $11.2 million; and an increase of $8.2 million in Consumer Education and Universal Service Fund ("USF") costs. With all of the above changes, including the reduction in the NTC, this results in an annual reduction in the NTC and SBC of $238.3 million.[8] The Company is further directed to reflect in rates the USF/Lifeline changes approved by Board Order dated July 16, 2003 in Docket No. EX00020091, I/M/O the Establishment of a Universal Service Fund Pursuant to Section 12 of the Electric Discount and Energy Competition Act of 1999.

Assuming an increase in BGS charges of approximately $360 million annually,[9] and a net increase of approximately $194 million resulting from the expiration of the Year Four EDECA rate discount and MTC, the net result of all adjustments is an overall increase in the Company's retail revenues in the approximate amount of $481 million annually. The Board **HEREBY APPROVES** this overall increase to be effective for service rendered on and after August 1, 2003.[10] The Board **HEREBY MODIFIES** the rate design set forth in the proposed Settlement in order to assure that a majority of residential customers receive no more than a 15 percent

[8] $232.1 million when based on the test year level of sales.

[9] This assumes the Commercial and Industrial Energy Pricing ("CIEP") classes experience the same average increase in BGS charges as do the Firm Pricing ("FP") classes.

[10] The Board notes that pursuant to the Summary Order, final tariff pages conforming to the terms and conditions of the Summary Order, were submitted by the Company and became effective for service rendered on and after August 1, 2003.

increase on an overall annual basis, including the impact of reflecting actual BGS rates, as of August 1, 2003.

Additionally, as directed in the Summary Order, the Board **FURTHER DIRECTS** the Company to continue to file monthly reports with the Board that show, for each NUG project, the energy and capacity purchased (Mwh and Mw), the amount paid for the energy and capacity, the disposition of the energy and capacity (i.e., whether it was sold in the wholesale market or otherwise), the amount received from the sale of the energy and capacity, as well as the value of the energy if it were priced at the average monthly PJM LMP and capacity deficiency rate, and the value if it were priced at the rate payable for BGS supply obtained pursuant to the statewide auction.

Except as to the foregoing modifications, the proposed Settlement is supported by the record, and while non-unanimous, it takes into account evidence and arguments of non-signatories, as well as signatories. As discussed above, the non-signatories were afforded the opportunity to address concerns regarding the proposed Settlement to the Board. Additionally, many of the non-signatories participated actively in the settlement discussions. By the modifications and clarifications made herein, the Board has further addressed various concerns of non-signatory parties upon careful consideration of their Exceptions and Replies to Exceptions. As to cost of service and rate design concerns raised, the decision rendered herein ensures that overall class rate increases on August 1, 2003 are within a reasonable range of billing impacts. In particular, with a total rate increase of 13.6 percent for the PSE&G system, the principal residential, commercial and industrial rate classes realize overall rate impacts that range several percentage points above and below the system 13.6 percent overall average increase, from an approximate 8 percent for the HTS Subtransmission customer class to 15 percent for residential customers. This is a reasonable result given the significant number of matters associated with this decision having rate implications to become effective on August 1, 2003, including distribution base rates, recovery of deferred balances, MTC change, and nuclear decommissioning funding change, as well as the scheduled August 1, 2003 change in BGS rates and termination of EDECA-mandated rate discounts. The Board also finds that the proposed Settlement's provision that the Area Development Service should be reviewed as part of the Board's consideration of the pending Smart Growth filing is reasonable and will provide for a review of related issues in a comprehensive and coordinated fashion. For all of the foregoing reasons, this Decision and Order ensures the provision of safe, adequate and proper service at just and reasonable rates.

DATED: **4/22/04**

BOARD OF PUBLIC UTILITIES
BY:

SIGNED

JEANNE M. FOX
PRESIDENT

SIGNED

FREDERICK F. BUTLER
COMMISSIONER

SIGNED

CAROL J. MURPHY
COMMISSIONER

SIGNED

JACK ALTER
COMMISSIONER

COMMISSIONER HUGHES, Dissenting in Part:

I join my fellow Commissioners in the resolution of these matters with one exception. I dissent from the determination to amortize the $155 million excess depreciation reserve over a 29-month period. I am not persuaded that there is an economic or other valid analytical basis for this amortization time period. I would have utilized a longer period of time more consistent with other amortization schedules, particularly given that at the expiration of the 29 months, there may be a further rate increase upon the financial review of the Company'.

SIGNED

CONNIE O. HUGHES
COMMISSIONER

ATTEST:

SIGNED

KRISTI IZZO
SECRETARY